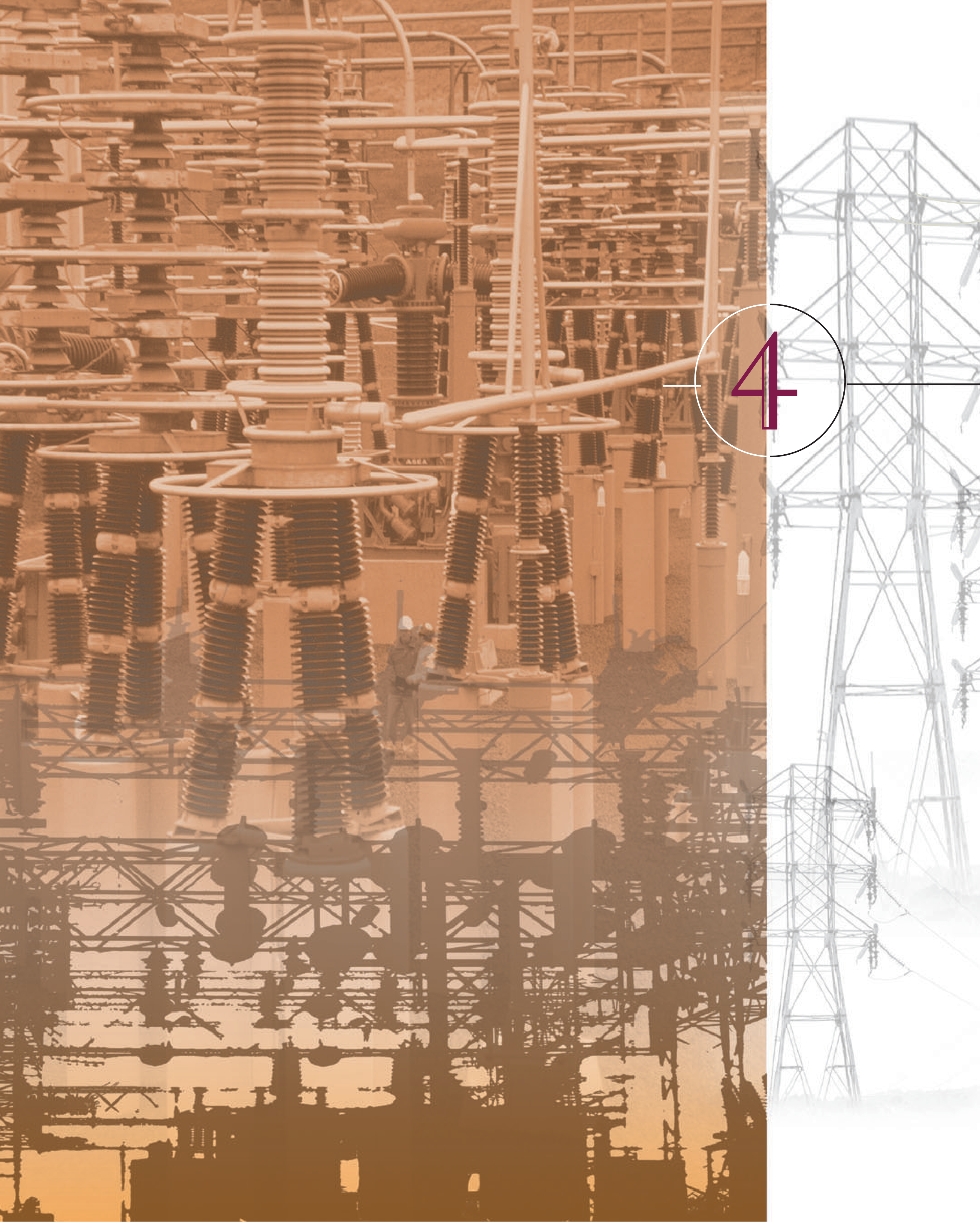


4

Improving transmission system operations should be the first element of a coordinated strategy to address transmission bottlenecks. Operational improvements can be implemented more quickly and at lower cost than construction of new transmission facilities. Needed improvements include: using market forces to manage transmission congestion through better price signals; voluntary load-reduction programs and targeted energy efficiency and distributed generation; relying on better real-time information to determine safe operating limits; and ensuring mandatory compliance with reliability rules.

Relieving Transmission Bottlenecks Through Better Operations

Ensuring the reliability of the transmission system has always been paramount. The primary objective of reliable transmission system operation has been to minimize the risk of large-scale blackouts. In extreme situations, temporary "rolling blackouts" have been imposed in parts of the system in order to maintain the integrity of the remainder of the system.

Current rules and operational procedures for addressing transmission bottlenecks reflect traditional operating practices based on experiences developed when electricity transactions were smaller in volume, involved fewer participants, and did not routinely span multiple regions. These rules and procedures embody a central-planning approach that gives little consideration either to the commercial value of electricity trade and the cost to consumers of lost trading opportunities, or to customers' willingness to accept compensation voluntarily for interruptions of electricity service.

Consistent with DOE's vision, market forces, not central planning, should be relied upon to the extent feasible to ensure reliability and to efficiently allocate transmission services when they become scarce. Increasing reliance on market forces to improve transmission system operations is a needed next step in the transition to a reliable transmission system that supports fair and efficient competitive regional wholesale markets that lower the cost of electricity to consumers.

This is not to suggest that market forces, alone, will be adequate to ensure reliability. In competitive wholesale markets, there is an even greater need than in the past for agreed-upon mandatory approaches to reliability management and real time operations. However, market forces should serve as a first line of defense before turning to these approaches.[33]

[33]For additional background on this discussion, see the Issue Paper, "Transmission System Operation and Interconnection," by F. Alvarado and S. Oren.

4

Pricing Transmission Services to Reflect True Costs

The first step toward increasing the role of market forces in managing transmission system operations efficiently and fairly is increasing the role of price signals to direct the actions of market participants toward outcomes that improve operations. Improving operations by relying on accurate price signals may, by itself, alleviate the need for some construction of new transmission facilities. Moreover, when new construction is needed, price signals will help market participants identify opportunities and assess options to address bottlenecks.

Several aspects of transmission operations, including congestion and losses, could be effectively addressed by pricing based on the principle that if market participants see the true costs of transmission services reflected in prices, they will use or procure these services efficiently. For example, pricing principles should encourage location of new generation in congested areas as opposed to location in areas with no congestion. Thus, reliance on uplift charges, in which costs are recovered from all transmission users on an equivalent basis, should be minimized.[34] Here, we focus on examples where application of these principles may be especially important for addressing transmission bottlenecks.[35]

Although curtailing some transactions is essential to ensure reliability when transmission lines are in danger of being overloaded, the economic losses associated with these curtailments can be reduced by sending price signals that will allow market participants to choose which transactions to curtail in response to the relative value of the transactions. Congestion pricing, in which the party that creates congestion pays for the costs of relieving it, is a powerful example of using

[34]Uplift charges are charges paid by all users; these charges represent costs that are difficult to apportion to particular market participants or that regulators allocate evenly among all users in order to achieve other policy objectives. In cases where uplift charges must be used to recover costs, however, performance-based regulations (discussed in Section 3) that provide incentives to minimize these charges and improve operational efficiency should be considered.

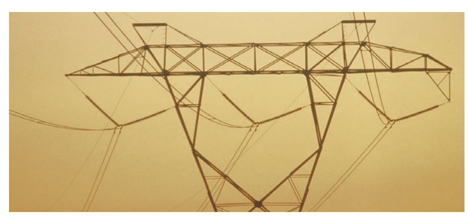
[35]For additional background on this discussion, see the Issue Paper, "Transmission System Operation and Interconnection," by F. Alvarado and S. Oren.

economic signals to relieve congestion efficiently. FERC's Order 2000 identifies reliance on market-based mechanisms to manage congestion as one of the eight functions of RTOs.

Transmission of electricity is not 100 percent efficient; losses, which result from the heating of lines and transformers, are inevitable, so delivering 100 MWs of electricity to an end point requires that more than 100 MWs be put into the transmission system. Losses depend on a variety of factors, including the physical properties of transmission facilities, the distance the electricity must travel, and the current use of transmission facilities by others. The costs of system losses are sometimes included in uplift charges borne equally by all transmission system users, which leads to inefficient use of the system. More accurate pricing and allocation of transmission losses will lead to more efficient markets because participants can see and respond to the true costs of using the transmission system.

Transmission pricing should recognize the inherent differences between intermittent, low-capacity-factor renewable energy sources that are often located far from loads (such as wind energy) and conventional generation, which is not intermittent. Pricing should not unduly disadvantage renewable power plants. For example, wind plants must pay for their own ancillary services. However, because of the inherent difficulty of precisely scheduling transmission needs for wind plants on a day-ahead basis, these plants should be allowed access to a real-time clearing market for differences, subject to non-punitive penalties based on cost, and/or allowed a wider clearing band for scheduling, as has been proposed by several states.

When we propose greater reliance on competitive economic forces to procure and apportion the costs of transmission services, we must recognize that markets for electricity and electricity services are still maturing. Approaches for organizing markets must minimize the risks of unintended design flaws that can be exploited by market participants. There is a need to develop methods for "testing" market rules in controlled laboratory-like settings to identify and correct design flaws prior to implementation. While we are gaining experience with markets, there must be safeguards—i.e., close oversight and rapid, deliberate response by FERC, including stringent penalties—to prevent market abuses. FERC has already initiated activities to increase its capability to monitor electricity markets more aggressively.



RECOMMENDATION

- DOE, working with FERC, will continue to research and test market-based approaches for transmission operations, including congestion management and pricing of transmission losses and other transmission services.

4

Increasing the Role of Voluntary Customer Load Reduction, and Targeted Energy Efficiency and Distributed Generation

Enabling customers to reduce load on the transmission system through voluntary load reduction or through targeted energy efficiency and reliance on distributed generation are important but currently underutilized approaches that could do much to address transmission bottlenecks today and delay the need for new transmission facilities.

Voluntary Customer Load Reduction

Allowing the "demand side" of regional wholesale electricity markets to interact with the "supply side" is a critical missing element in the transition to fully competitive, fair, and efficient markets. Without meaningful participation by the demand side, today's market is, at best, half a market. Relaxing the current electric system operating principle that all customer demand must be served at any cost is the key to rational provision of reliable and affordable electricity services. We can keep most of the lights on at a lower total cost to all customers if we allow those who are willing to turn their lights off voluntarily (e.g., in response to economic incentives and price signals) to do so.

Voluntary load-reduction programs encompass a variety of strategies that enable customers to curtail or displace load from their local utility in response to system conditions. Providing opportunities for customers to respond to the true costs of electricity is not the same as enabling retail choice; voluntary load-reduction programs can be operated in states where there is retail choice as well as in states where incumbent utilities continue to provide retail electricity service.

A full-scale effort is needed to understand how customers would voluntarily reduce electricity loads, conduct pilot programs, assess the impacts of these programs on wholesale markets and system reliability, and develop new technologies for price transparency and customer participation in the market.

Eliciting load response from customers will not be easy. Flexible programs will be required in view of these key considerations:

New York ISO Demand-Response Programs

The New York Independent System Operator (NYISO) operated two demand-response programs in 2001: the Emergency Demand Reduction Program and the Day-Ahead Demand Reduction Program. Both are examples of the types of programs needed to enable voluntary customer load reduction in wholesale markets for the purposes of enhancing system reliability and increasing market efficiency.

The Emergency Demand Reduction Program is a "call"-type program (i.e., customers agree in advance to curtail load when called to do so by NYISO) but is voluntary in that there are no penalties for choosing not to curtail when called, so payment is based on a participant's performance in each hour of a curtailment event. In summer 2001, the program was operated four times because of shortages in operating reserves. On average, the program delivered 450 MW, which is a significant share of the 1,800 MW operating reserve that NYISO maintains.

The Day-Ahead Demand Reduction Program is a "quote"-type program (i.e.. customers are given an opportunity to offer load reductions to the wholesale market). In summer 2001, the program operated during July and August and achieved modest load reductions. Efforts are under way to improve the design and operation of the program for summer 2002.

Source: New York ISO. http://www.nyiso.com/services/documents/groups/bic_price_responsive_wg/demand_response_prog.html

- Some customers may be quite willing to view reduction of their load for economic purposes as a new source of profit/savings, but others may only be willing to reduce their loads in response to circumstances such as true system reliability emergencies.
- Many customers will require substantial advance notification to reduce load and will want to limit the duration and frequency of interruptions in service; others will be more flexible.
- Real-time pricing is essential for allowing customers to determine how much power they wish to use based on the actual price of electricity at any point in time. However, other programs, such as priority service and demand bidding, should also be explored to accommodate customers who do not wish to respond to real-time prices.

DOE, the states, and private industry can help enable widespread customer participation in voluntary load-reduction programs by educating consumers about successful programs. DOE can also stimulate the development and dissemination of successful approaches and technologies. Advanced meters must be deployed that allow customers to receive signals in real time (e.g., hourly prices for electricity) and new system integration techniques must be developed and demonstrated to automate responses to these signals.

Modifying transmission operation control systems to accommodate load reduction on an equivalent basis with electricity generation poses a series of challenges. First and most important, the system reliability rules and practices underlying current telemetry requirements and control procedures must be reviewed and redefined from a technology-neutral point of view, without compromising system reliability. Second, new communication and control technologies consistent with these redefinitions must be developed and implemented. DOE can help industry accelerate these needed changes.

Targeted Energy Efficiency and Distributed Generation

Targeted energy efficiency and distributed generation are approaches through which customers can reduce electricity loads on the transmission system, alleviate bottlenecks, and delay the need for construction of new facilities. They are complementary strategies to voluntary customer load-reduction programs.

Utilities and government have spent more than 25 years developing and implementing proven energy-efficiency programs and standards that save consumers money. Today, funding for utility-led energy-efficiency programs is significantly lower than before industry restructuring because recovering the costs of these programs conflicted with rate reductions and freezes and the need to recover the much larger costs of utilities' stranded assets.

Regulators should re-evaluate and consider expanding utility support for energy efficiency programs in view of their potential benefits to the electricity system as well as their direct benefits to customers in the form of lower electricity bills. State regulators need to eliminate

Summer 2001 Demand Reductions in California

California's experiences during the electricity crisis in summer 2001 offer important lessons about peak demand reduction. According to the California Energy Commission, Californians used 8.9% less electricity during peak hours in 2001 compared to 2000 when adjusted for growth and weather (see http://www.energy.ca.gov/).

These are very large savings compared with what almost all observers at the time expected and historical behavior patterns. In other words, demand-reducing programs performed very well, and these reductions were of great importance during the crisis. However, although an estimated 30 percent of these savings related to investment in more efficient end-use devices and on-site generation will likely persist, the remaining reductions are the result of changes in behavior and operations that may not continue now that the crisis appears to have passed. California spent a large sum of (one-time) funds strongly encouraging consumers to reduce energy use. Many consumers did so for reasons including: the desire to be good citizens, concerns about high electricity bills, and the prospect of receiving a 20 percent electricity bill rebate if they achieved 20 percent savings.

Thus, although demand reduction can play an important role in relieving transmission bottlenecks, the crisis situation to which Californians responded in summer of 2001 is not a desirable model for future efforts. The crisis in California was very expensive. The goal should be to avoid such crises, in California and elsewhere. Long-term demand reduction programs, enhancement of the transmission system, and new supplies are all essential to achieving this goal.

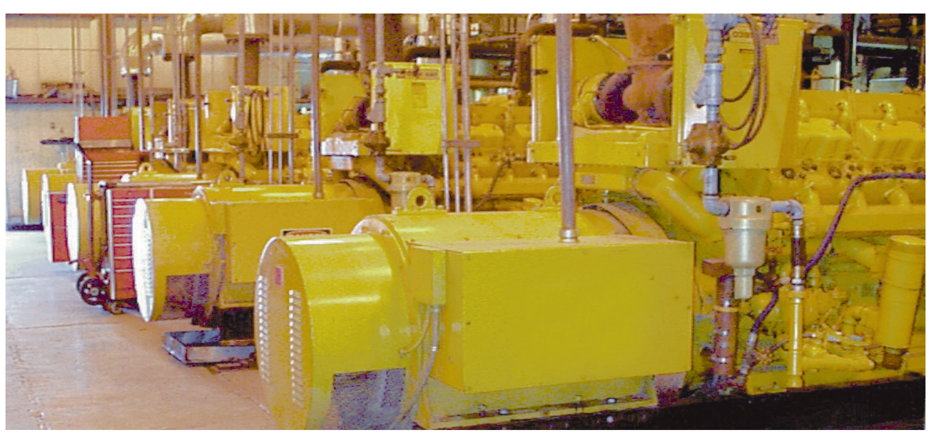
disincentives facing utilities and third-party energy service providers who wish to lower customer energy bills and help mitigate transmission bottlenecks though energy efficiency programs.

Distributed generation and storage allows customers to reduce reliance on the transmission system by “distributing” or placing generation sources (such as photovoltaics; combined heat and power systems; and small, clean generators, including microturbines and fuel cells) and energy storage closer to the locations at which electricity is used, e.g., at customers’ homes or businesses. For distributed generation that also incorporates combined heat and power technologies, the economics are enhanced by opportunities to use the heat produced in the conversion of fuel to electricity. Other applications benefit from the increase in power quality offered by certain distributed technologies (e.g., energy storage).

There is some local utility resistance to increasing customers’ reliance on distributed generation. This resistance is based on technical concerns (e.g., safety of utility crews working in the field who do not know that current is flowing from distributed resources) and a combination of regulatory (e.g., loss of sales revenues) and competitive considerations (e.g., high charges for back-up power from the utility).

Current utility procedures for interconnecting distributed generation to the electricity grid are generally expensive and non-transparent. The Institute of Electrical and Electronics Engineers (IEEE) is working to establish technical interconnection standards in its draft standard IEEE P 1547. This effort must be completed soon to help promote distributed generation solutions. Standardized interconnection procedures (agreements, rules, and business procedures) are also needed to reduce costs and clarify requirements.

Current rate-making practices create disincentives for utilities to “lose” load to distributed generation (as well as to energy efficiency) despite the benefits to the system and the potential cost savings to customers from these two strategies. State regulators should examine the current regulatory disincentives to energy efficiency and distributed generation and address them consistent with the public interest in ensuring cost-effective consumer investments in distributed generation and energy efficiency.



RECOMMENDATIONS

- DOE will work with FERC, the states, and industry, and conduct research on programs and technologies to enhance voluntary customer load reduction in response to transmission system emergencies and market price signals.
- DOE will work with states and industry to educate consumers on successful voluntary load-reduction programs. DOE will disseminate information on successful approaches and technologies.
- DOE will continue to work with NGA, regional governors' associations, and NARUC to remove regulatory barriers to voluntary customer load-reduction programs, and targeted energy efficiency and distributed generation programs that address transmission bottlenecks and lower costs to consumers.
- IEEE should expeditiously complete its technical interconnection standards for distributed generation.
- DOE will work with NGA and NARUC to develop and promote the adoption of standard interconnection agreements, rules, and business procedures for distributed generation.

4

Using Improved Real-Time Data and Analysis of Transmission System Conditions

The maximum electrical loads allowed on the transmission system today are estimated conservatively. Total Transfer Capability (TTC), which is the basis for establishing Available Transfer Capability (ATC), has traditionally been determined by a static analysis of acceptable system conditions—that is, system operators assumed conservative values for ambient conditions, such as air temperature and wind speed, that affect the safe and reliable operation of transmission lines and other transmission facilities. This practice was acceptable in the past because of the lack of measurement, communication, and analysis tools to determine the real-time status of the electric system. In addition, it was easier to conduct a static analysis and overbuild the transmission system than to conduct a dynamic analysis so that the system could be operated more efficiently, i.e. closer to its actual safety limits, which vary over time.

The increased demand for transmission services and the increasing difficulty in getting new transmission lines built compel us to better understand the limits of safe and reliable transmission system operation. As ambient conditions change, so will TTC. A dynamic system analysis that uses real-time data instead of the conservative proxies used in a static analysis provides a better estimate of TTC and would allow operators to safely move more power across existing lines.

In addition to the corresponding increase in ATC that would result from a more precise assessment of TTC, dynamic analysis can further increase ATC by identifying unused transmission rights that can be made available to the market on a nonfirm basis. The overall result of using dynamic transmission system analysis could be a substantial increase in ATC, a reduction in transmission congestion, and more efficient use of the transmission system.

Recent advancements in measurement, communication, and analysis tools now make dynamic analysis a possibility.[36] In some cases, a change from a static transmission system analysis to a dynamic analysis may be the most cost-effective way to reduce a transmission bottleneck.

RECOMMENDATION

- DOE will work with industry to demonstrate and document cost-effective uses of dynamic transmission system analysis.

4

Ensuring Mandatory Compliance with Reliability Rules

Ensuring reliability has and will remain a fundamental priority for the nation's electricity transmission systems. The procedures that have in the past been used to set and enforce rules to ensure reliability must change to be consistent with and supportive of competitive wholesale electricity markets.[37]

The 1990s witnessed an increase in the number of large-scale blackouts and near misses. Some have expressed concern that this increase is evidence of the losing battle firms now face in trying to manage reliability while operating in competitive business environments that provide few if any economic

[36]A description of tools, such as the Wide Area Measurement System (WAMS), that would support more precise determinations of the dynamic state of the transmission system can be found in Section 5, "Relieving Transmission Bottlenecks Through Effective Investments." See also the Issue Paper, "Advanced Transmission Technologies," by J. Hauer, T. Overbye, J. Dagle, and S. Widergren.

[37]For additional background on this discussion, see the Issue Paper, "Reliability Management and Oversight," by B. Kirby and E. Hirst.

rewards for continued stewardship of the public interest in electricity system reliability.

Industry has stated clearly that it can no longer rely on the historic system of voluntary compliance with rules to ensure the reliability of the nation's interconnected transmission systems because of the competition among firms in today's marketplace.[38] There is widespread agreement that mandatory rules are now required to ensure transmission system reliability. In the West, the WSCC is creating a mandatory system based on contractual agreements with its members. This is a significant improvement over the historic voluntary system, however, federal legislation to create a mandatory system remains essential.

Foremost among the issues that must be considered in reviewing reliability rules is the recognition that these rules directly impact market operations (for example, TLRs curtail certain commercial transactions, as explained in Section 1). An open, inclusive process for reviewing and establishing reliability rules is required in view of their economic implications.

New reliability rules must accommodate variations in transmission system designs and build upon the knowledge of local transmission system operators in open rule-setting processes. However, it is essential that local variations do not hinder the operation of competitive regional electricity markets and are not used unfairly to give a competitive advantage to one group of market participants at the expense of others.

Although reliability has never been ensured "at any cost," the costs of reliability to consumers should be explicitly accounted for when reviewing reliability rules. At a minimum, the penalties for violating reliability rules should reflect the costs imposed on society by these violations, e.g., the cost of replacing the reliability services that are not provided by the violator.

Similarly, as a cornerstone of restructuring, we should allow consumers to pay for a higher level of reliability than that provided by the current electricity system. A critical barrier to informed consumer choice about reliability, which includes power quality, has been the lack of public data on the subject. Although records are kept by utilities, their interpretations of reliability and power quality events vary

Table 4.1

Summary of Major Electricity Reliability Events in North America
Northeast blackout: November 9-10, 1965
New York City blackout: July 13-14, 1977
Los Angeles earthquake: January 17, 1994
Western States cascading outage: December 14, 1994
Western States events in Summer 1996 - July 2, 1996—cascading outage - July 3, 1996—cascading outage avoided - August 10, 1996—cascading outage
Minnesota-Wisconsin "near miss": June 11-12, 1997
Northeast ice storm: January 5-10, 1998
Upper Midwest cascading outage: June 25, 1998
San Francisco blackout: December 8, 1998

Source: J. Hauer and J. Dagle. 1999. *Review of Recent Reliability Issues and System Events*. Download from http://www.eren.doe.gov/der/transmission

[38]North American Electric Reliability Council. 2001. *Reliability Assessment, 2001-2010*. Download from http://www.nerc.com

considerably, so data from different utilities are often not comparable. Of greater concern is that consumers do not routinely have access to these data. For example, when businesses experience interruptions that disrupt their processes, it starts a long and expensive process of data collection and analysis to diagnose the problem before a solution can be prescribed. Without these data, consumers cannot make informed decisions and cannot fully assess the significance of electricity reliability and power quality and thus the value of options available to address them.

RECOMMENDATIONS

- Federal legislation should make compliance with reliability standards mandatory.
- Current reliability standards should be reviewed in an open forum to ensure that they are technically sound, nondiscriminatory, resource neutral, and can be enforced with federal oversight.
- Penalties for noncompliance with reliability rules should be commensurate with the costs and risks imposed on the transmission system, generators, and end users by noncompliance. Penalties collected should be used to reduce rates for consumers.
- DOE will work with industry and NARUC to promote development and sharing of best transmission and distribution system operations and management practices.
- DOE will work with FERC, state PUCs, and industry to ensure the routine collection of consistent data on the frequency, duration, extent (number of customers and amount of load affected), and costs of reliability and power quality events, to better assess the value of reliability to the nation's consumers.